REPORT OF

THE DEPARTMENT OF THE INTERIOR ON

H.R. 3334, THE ROYALTY ENHANCEMENT ACT OF 1998

APRIL 30, 1998

TABLE OF CONTENTS

A. EXECUTIVE SUMMARY

This document is an analysis of the effects of H.R. 3334 if it should be enacted as introduced. This Bill would relinquish many of the Federal Government's long-established legal rights it currently has as mineral lessor and would relieve lessees of many of their long-established obligations. Many of the specific components of the Bill would decrease the value of Federal oil and gas royalties.

It should be noted at the outset that MMS currently has the authority under existing law and lease agreements to take royalty in kind at its option.[1] Because any law that is passed, in order to be enforceable, must conform to existing lease agreements, no new legislation may negatively affect the lessee's contract with the government. However, Congress is free to unilaterally change those existing lease agreements to affect the Federal Government's rights. By virtue of the contractual constraints, any new legislation, by definition, can only negatively affect the Government's interest in favor of the lessee.

First, the Bill would adopt many of the positions taken by the oil and gas industry in historic valuation disputes with the Department of the Interior, disputes the Department has consistently won. The Bill would absolve the lessee from its duty to market and require the Federal Government to begin paying for gathering production upstream of the royalty meter; moving unseparated, bulk production; and conditioning and treating production.

Second, the Bill would mandate Royalty-in-Kind (RIK) programs in areas where unfavorable conditions exist for an RIK program, such as taking *de minimis* volumes in remote areas, taking production at less than marketable condition, and paying above market rates for transportation.

Third, the Federal lessor would assume the costs of marketing oil and gas in an RIK program where production is sold downstream of the lease. Under the historic in-value royalty system currently in effect, the Federal Government does not share in such costs.

Fourth, the Bill's criteria under which Government marketing agents could sell to themselves or affiliates are so broad and unenforceable that they would assure continuation of disputes between marketers and the Department over sales prices and lead to substantial administrative costs for both the Federal Government and marketers.

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[1] This authority exists with respect to all but section 6 leases, which were entered into by the States of Texas and Louisiana in the 1940's. These leases were assumed by the Federal Government. There are only 402 such leases in existence, accounting for 21 million barrels of oil and 126 million Mcf of gas production annually (i.e., less than 3 percent of total Federal production). These leases give the lessee the option to pay in kind or in value. Legislation cannot legally affect the contractual rights of the lessee.

In summary, this Bill would drastically reduce the options and legal rights of the Federal Government as mineral lessor and hinder the Government in its duty to assure a fair return to the public for its oil and gas resources.

Ambiguities and vagueness in many areas of the Bill make it difficult to discern exactly how some provisions operate. Certain provisions of the Bill, such as those addressing transportation cost reimbursements, will actually increase costs to the Government and reduce royalty revenues commensurately.

We estimate that the costs associated with the Bill are in the hundreds of millions of dollars per year, while the associated administrative costs savings are less than $8 million per year. Our estimates for potential revenue gains vary from negative numbers to tens of millions. Any such potential positive gains can be realized today and, therefore, should not be attributed to this legislation. MMS's existing right to take royalties in kind and the capability being developed through our RIK pilot programs, means that MMS can realize all of these revenue gains without the many costs associated with this legislation, and without revenue losses from areas where RIK is not a viable option. Thus, H.R. 3334 will have a substantial negative annual cost impact on the Treasury and will not enhance revenue compared to current statutory authority.

B. MAJOR ISSUES

The following summarizes the major issues that concern the Department with respect to H.R. 3334.

1. Mandatory Royalty in Kind

The Bill requires the Government to take royalty volumes of both oil and gas in kind for all Federal leases onshore and offshore. Requiring RIK for all Federal oil and gas production virtually guarantees revenue losses because:

- The value of the current option of taking in kind and in value in areas where each is economically justified is eliminated.
- Taking of de minimis production in remote areas is administratively inefficient and will be a revenue loser compared to the current system.
- Oil and gas markets in some regions are limited and oversupplied. Adding another player to such markets without available pipelines and purchasers will not add value.

> **Mandatory RIK Guarantees Revenue Losses to the U.S.**
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> Most oil and gas leases require the lessee to deliver royalties in kind or pay in value at the discretion of the lessor. The Government can already take royalties in kind when it is beneficial to the taxpayer. H.R. 3334 would force the Government to take royalties in kind where it would lose money. This is contrary to the Texas RIK program.

- The potential for RIK to add value to crude oil has not been thoroughly evaluated, but prior experience with RIK pilots indicate that the potential is minimal at best, and less than minimal if the Government administration of the program is restricted in any way.
- A host of regionally-specific production and transportation situations argue against forced RIK (e.g., capacity constraints).
- The Government has no control over production decisions and would be at the mercy of the lessee in situations where over production could result in transportation, processing, and refining capacity constraints.

2. Imposition of a Rigid Statutory System

H.R. 3334 would impose a rigid "one size fits all" statutory scheme that eliminates the ability of the Executive Branch to use its existing RIK authority to jointly develop with affected parties a flexible system that works best for individual areas/situations. MMS is currently designing pilot programs to identify the type of RIK programs that would operate best under varying conditions.

Any decisions on broader implementation should follow and use the pilots' results. Just a few examples of the Bill's inflexibility are:

- Sales would only be made by marketing agents, precluding direct sales to Government facilities without marketing agent involvement or sales by an in-house marketer.

- Competitive sales at the lease without a third party agent are precluded.

- No provisions are provided where no bids or unacceptable bids are submitted.

- No provisions are provided where royalty production may be used for national security interests.

- State in kind programs for just the State shares are not allowed.

- Marketer negotiation of the best transportation rates on certain pipelines is precluded.

3. Technical Provisions

H.R. 3334 contains a variety of technical requirements for gathering, transporting, treating, and processing that in sum transfers new obligations to the Government and increases many of the costs and responsibilities historically borne by producers.

a. Marketable condition

H.R. 3334 would transfer costs to the Government which historically have been the responsibility of the lessee.

The Bill would eliminate the current requirement for lessees to place production in a condition acceptable to purchasers and substitute a requirement for acceptance by transporters. This is a significantly less stringent condition that would now require the U.S. to begin paying for sweetening, treating, and conditioning services. Since the initial transporter is often owned by the lessee or its affiliate, the Bill essentially allows the lessee to define marketable condition.

b. Gathering

Although the distinction between gathering and transportation in the Bill is unclear and confusing, the overall effect will be to move the dividing line between gathering and transportation closer to the wellhead, thereby shifting costs from producers to the Government. For OCS leases, approximately 25 percent of crude oil and 10 percent of natural gas movement upstream of the royalty meter, which is now paid for by lessees, would be paid for by the U.S. For onshore leases, about 50 percent of crude oil and 25 percent of natural gas movement upstream of the royalty meter, which is now paid for by lessees, would be paid for by the U.S.

c. Transportation

The Bill would require the U.S. to begin paying for transportation of non-royalty-bearing substances (e.g., water) in bulk production volumes moved from the lease. Movement of bulk production downstream of the lease is a growing practice and would require the U.S. to assume an increasingly large cost burden compared to today. Further, the rates that the U.S. would be required to pay for transportation under the Bill would also increase dramatically compared to those currently paid by lessees. In some cases the Bill would require the U.S. to pay the highest rates charged to third parties.

d. Processing/Treating

Taken together with a redefined "marketable condition" provision, the Bill would shift to the Government much of the cost of cleaning, decontaminating, and other field services. Further, the substantial amount of production currently processed by lessee's affiliates at actual (relatively low) costs would be processed by the Government at much higher, commercial rates under the Bill.

e. Marketing

All costs to market oil and gas production would be assumed by the U.S. under the Bill, whereas, under the current royalty system, these costs -- which are substantial -- are borne by lessees. Ironically, the Bill would actually create new marketing costs (to be borne by the U.S.) in the many cases where there are currently no such costs, i.e., for the substantial volumes of crude oil production simply moved from major producers to their own refineries.

H.R. 3334 creates a new middleman. That is, new marketing costs would be borne by the U.S. for crude oil produced on Federal lands. The majority of that oil currently moves directly to producers' refineries.

4. Negative Revenue Impacts

H.R. 3334 will have a substantial negative cost to the American public. Some of the annual costs under the bill are readily quantifiable as the table indicates. Other costs (such as litigation, market risk, marginal property burdens, etc.) cannot be easily quantified.

a. <u>Quantifiable annual costs/savings</u>

	Low Estimate Million $	High Estimate Million $
Costs		
Additional Royalty Costs	182.4	366.6
Small Refiner Administrative Fee	0.8	1.0
Net Receipts Sharing Elimination	0.0	6.2
Total Costs	183.2	373.8
Savings		
Potential “Uplift”	35.2	0.0
Administrative Savings	7.3*	7.3*
Total Savings	42.5	7.3
Net Annual Cost to the American Public	**140.7****	**366.5****

*Reflects first 8 ½ years after passage of the Act.

****The net annual cost to the American public will increase as other costs become quantifiable.**

b. <u>Unquantifiable costs</u>

- The requirement that the Government must offer 40 percent of royalty oil to eligible small refiners at the lowest prices essentially prohibits the Government from receiving the highest and best prices for 40 percent of royalty oil.

- H.R. 3334 will significantly increase our litigation burden in the royalty context. The bill places DOI in the position of relying on various marketing entities, most of whom will have a serious conflict of interest because they are affiliated with producers who are typically opposed to DOI on royalty issues. Litigation would arise over issues such as when deliveries and imbalances must be taken; as well as over marketers' decisions made in conflict of interest situations, because the marketing entity that DOI must use will favor the producer that it is affiliated with.

- The Bill does not address who would be liable, Qualified Marketing Agents (QMA), purchasers, etc., in case of default on payment from RIK sales.

- The imbalance provisions of the Bill are biased heavily in favor of the producer, particularly those provisions requiring the Government to forfeit royalty volumes if not taken. The Federal Government currently does not participate in imbalances, as lease terms and regulations require royalty on the full volume of production measured during the month of production. Requiring the Government to participate in imbalances will deny the public full and timely benefit of its share of production.

- The mandate of the Bill to take royalty in kind from marginal properties in remote areas greatly increases administrative costs and severely limits the Government's ability to enhance the value through aggregation. In those situations, the Government is at best entirely dependent on the producer for storage and transport to market. At worst, the Government could be forced to take a fraction of the small volumes and arrange to bring it to market separately.

- The Bill does not provide safeguards against price manipulation between QMA's and their affiliates. The requirement to demonstrate control on an asset basis will mean that only the operator of the asset will have an affiliation with the owner of the asset. Thus, the QMA could sell royalty production back to an affiliated refiner or other affiliated party without demonstrating opposing economic interests or even demonstrating the market value of the production or fair value of the contracted services.

- The Bill will require the Government, through the QMA, to incur operational risks associated with pipeline imbalances, costs not currently passed on to the Government.

- The Government also risks substantial revenue losses in regional markets that are oversupplied -- a situation where there is little potential for revenue to be gained.

- The Bill doesn't address how the Government is to dispose of its royalty production for leases that receive no or inadequate bids from QMA's; the Government could easily lose access to its royalty volumes in these situations because of the requirements for daily taking of in-kind volumes by QMA's.

- Additional administrative costs will be incurred for selection and monitoring of QMAs, reimbursement to lessees for transportation costs, RIK start-up costs, etc.

C. SECTION-BY-SECTION ANALYSIS

The following describes the detailed effects of the Bill compared to the current "in value" regulatory framework, beginning with Section 2 of the Bill.

1. SEC 1. SHORT TITLE; TABLE OF CONTENTS

No comment.

2. SEC. 2. DEFINITIONS

(1) *Affiliate; affiliated*.

This definition is similar to the definition of "arm's-length contract" currently found in 30 CFR 206 (1997) but omits the requirement that transactions must take place in the market place between parties of opposing economic interests. It also differs from the current regulatory definition by determining affiliation and control on an asset-by-asset and lease-by-lease basis, instead of on a contract basis. The definition potentially circumvents the long-standing economic principle that the value of a commodity or service is best determined in a competitive, open market between parties with opposing economic interests.

This definition applies to two sections of the Bill. First, the Qualified Marketing Agent (QMA) could be affiliated with the lessee/producer or field operator but not have any direct control in the lease or in transportation, treating, and processing assets. The requirement to demonstrate control on an asset basis will mean that only the operator of the asset will have an affiliation with the owner of the asset. Thus, the QMA could sell royalty production back to an affiliated refiner or other affiliated party without demonstrating opposing economic interests or even demonstrating the market value of the production or fair value of the contracted services. The Bill does not provide safeguards against price manipulation between QMA's and their affiliates.

Second, this definition will allow for more transportation arrangements to be considered nonaffiliated, thereby forcing the Government to pay for transportation based on "actual rates" rather than actual costs.

The net effect of this definition is that more transactions will qualify as nonaffiliated without affording the Government the benefit of review or adjudication. Further, determining affiliation on an asset-by-asset basis will require additional audit effort.

(2) *Compensatory royalty*.

This definition provides for a payment to the royalty owner as compensation for production drained from the leased property. MMS will still have to collect and distribute compensatory royalties and adjudicate proper value of the drained production. (See also Sec. 8.)

(5) *Delivery point*.

This definition identifies the point where production is measured to determine the royalty quantity transferrable to the QMA; it equates to the point of royalty settlement and differs from the definition of delivery point in 30 CFR 208 (1997). In cases where the delivery point is downstream of the lease, the proposed legislation would have the Government pay for transportation to the delivery point. Such activity is now considered gathering and is not deductible from royalty value. The royalty impacts of this definition are substantial and are addressed in the analysis of Sec. 4(b) below.

(6) *Eligible small refiner*.

Under H.R. 3334, 47 refiners would qualify as an eligible small refiner able to purchase U.S. crude at the lowest prices.

This definition sets different, and apparently broader standards for an eligible refiner than currently defined in 30 CFR 208, which follows criteria given in the Emergency Petroleum Allocation Act for onshore leases (capacity does not exceed 175,000 barrels per day) and rules of the Small Business Administration (SBA) for offshore leases (capacity does not exceed 75,000 barrels per day). This definition would bring consistency between offshore and onshore leases on the criteria used for defining "eligible" refiner. The proposed criteria is 25,000 barrels more for offshore than today and for onshore leases it is 75,000 barrels less than today.

Under the employee requirement of the SBA, an eligible refiner can have no more than 1,500 employees. One of the current refiners in the program now has more than 1,500 employees and will be ineligible under current rules in the next contracting cycle. Modifying this provision as proposed in the Bill will enable "large" companies with small refining capacity to participate in the program.

(7) *Eligible small refiner portion*.

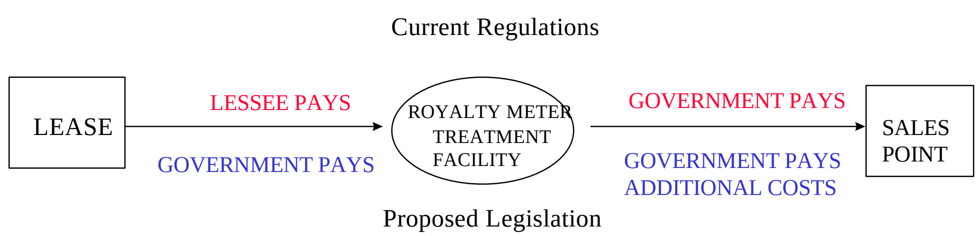
This definition requires that 40 percent of all royalty oil volumes be offered for sale to eligible small refiners, unless the Secretary determines that a greater share is in the public interest. The current small refiner program does not require the Government to offer crude oil to eligible small refiners. This mandate will exacerbate challenges with the current eligible refiner program to avoid volume type problems associated with small producing leases, delivery points, transportation problems, etc.

The pricing clause in Sec. 12(a)(4) would use the lowest prices to value this oil, thereby reducing the Government's revenue by a substantial amount and undercutting the Bill's fundamental premise that a QMA will take production and find the highest and best price. This definition essentially prohibits the Government from receiving the highest and best price for 40 percent of royalty oil. (See also Sec. 12 below.) The requirement to offer 40 percent of royalty oil to eligible small refiners will require continued management to administer. Finally, Section 12 (c) repeals the current administrative fees charged to eligible refiners, approximately $1 million per year.

(12) *Gathering*.

This term means the movement of production to a central accumulation point. It differs from the current definition of gathering in 30 CFR 206 which includes movement of production to a treatment point as well as to a central accumulation point. Because under the Bill most delivery points will be established at the lease, this definition would have the Government pay for what are now nondeductible gathering costs.

The following schematic demonstrates the difference between the current regulations and the Bill:



> **What is Marketable Condition?**
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> H.R. 3334 changes the definition of marketable condition so that in the San Juan Basin of New Mexico, where operators of coalbed methane pipelines accept gas with far greater amounts of carbon dioxide than do the main interstate pipelines servicing the area or end-use customers, the Government would have to pay to remove those impurities before it could sell the gas. This is a cost it currently doesn't bear.

By omitting the term "treatment" from the definition, the proposed legislation requires the Government to pay for treating and conditioning costs downstream of the delivery point. These costs are now considered costs of placing the production in marketable condition regardless of where they occur and are nondeductible expenses. The revenue impacts of this definition are addressed in Secs. 4(a) and 4(b) below.

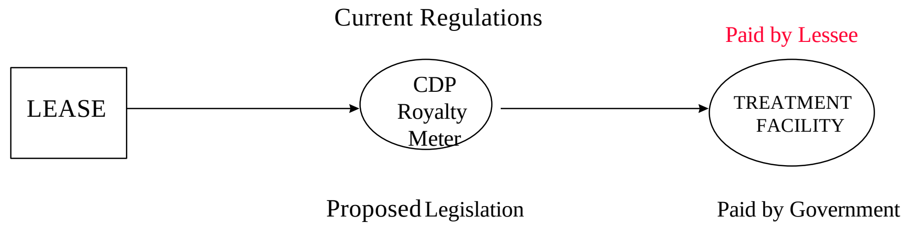
More importantly, the distinction between "gathering" and "transportation/transport," as defined in Sec. 2(34), is unclear and confusing, and the two definitions and their operation appear to contradict each other. This confusion can lead to multiple interpretations of the intent and workings of other provisions in the Bill, particularly those regarding reimbursement for transportation prior to the delivery point covered in Sec. 5(b). The only thing certain is that the Government will incur additional "transportation" costs under the Bill.

(18) *Merchantable condition; marketable condition.*

These terms define marketable condition as the condition of oil or gas that is sufficiently free of impurities to meet the requirements of or is **accepted by the transporter** of production from the lease. The definition also provides that the responsibility for the bearing of gathering and transportation costs is not effected by whether or not the lease production is in marketable condition.

The current definition of marketable condition in 30 CFR 206 requires lease products that are sufficiently free of impurities and otherwise in a condition to be **accepted by a purchaser**. In many cases transporters have less stringent quality or condition specifications than purchasers.

By changing marketable condition from the condition accepted by a purchaser to the condition accepted by the first transporter will cause the Government to pay for any sweetening, treating, and conditioning services performed downstream of the delivery point. These services are normally performed to ready the production for market and, as such, their costs are not allowable deductions under the current regulatory definition of marketable condition. Further, to the extent that the first means of transportation is owned by the producer or its affiliate, this definition allows the producer to self-define marketable condition (within the technical limitations of the pipeline). The royalty impact of the proposed definition, combined with the definition of "processing/process," is given in Sec. 4(a) below. The schematic illustrates this point:



(25) *Processing; process.*

These terms define operations that are designed to remove elements or compounds from oil or gas, including absorption, adsorption, or refrigeration, but excluding field processes such as pressure reduction, mechanical separation, heating, cooling, dehydration, and compression on the upstream side of the delivery point. This definition is the same as in 30 CFR 206, except that the definition in the Bill adds a qualification regarding the "upstream side of the delivery point."

"Processing" is usually a term applied to the separation of natural gas liquids and other contaminants in raw natural gas streams. It usually occurs well downstream of the lease, which under the proposed legislation, will also occur downstream of the delivery point. However, it conceivably could occur upstream of the delivery point. Current regulations provide for a credit, or processing allowance, against the value of separated products that are marketed. However, some "processes" are performed to place gas in marketable condition. For example, acid gas contaminants, such as carbon dioxide and hydrogen sulfide, are commonly removed by adsorption processes. These contaminants must be removed to make the gas marketable. Coupled with the definition of "marketable condition," the proposed legislation would shift to the Government much of the costs of cleaning, decontaminating, and otherwise placing production in marketable condition. The projected cost to the Government for these services is given in Sec. 4(a) below.

(34) *Transportation; transport.*

This definition identifies transportation as any movement, including associated or related activities to facilitate movement such as compression or dehydration, of royalty production downstream of the delivery point. (Current regulations permit a deduction for compression and dehydration in the computation of transportation allowances, provided those activities are a function of transportation.) Transportation includes movement of unseparated, bulk production away from the lease and movement of separated, identifiable production downstream of a well on the lease premises to a point off the lease. So, under the Bill all movement is transportation (i.e., costs borne by the Government) except movement of bulk, unseparated production on the "lease premises."

Under H.R. 3334, the cost of shipping water is transferred to the Government.

The Grand Isle system located in the Gulf of Mexico is one example where water is shipped with oil - 40 per cent by volume in this case. The cost to move this non-royalty-bearing water is approximately $1 million per year.

As stated in the analysis of Sec. 2 (12) above, the distinction between gathering and transportation is unclear and confusing and can lead to multiple interpretations.

By including the movement of unseparated, bulk production away from the lease in this definition, the proposed legislation will have the Government incurring the costs of transporting non-royalty bearing substances, such as water, that are now not deductible. In addition, including in the definition the movement of separated, identifiable production downstream of a well will cause the Government to pay for much of what is now considered nondeductible gathering costs. Combined with Sec. 4 (b), Gathering and Transportation of Royalty Oil and Gas, which provides in paragraph (2) that the Government will bear costs of transporting production to and beyond the delivery point, and Sec. 5(b), Reimbursement for Transportation Costs Prior to the Delivery Point, which provides that the Government will reimburse the lessee for transportation costs prior to the delivery point, this definition requires the Government to bear all costs of moving production away from the well. The royalty impact of this definition is addressed in the analysis of Sec. 4(b) below.

3. SEC. 3. RIGHTS, OBLIGATIONS, AND RESPONSIBILITIES

Sec. 3(a)--Rights, Obligations, and Responsibilities of the United States

Sec. 3(a)(1)--General Rule

This section mandates that the Government take all its royalty oil and gas in kind at the delivery point. This is contrary to most lease terms, which give the Government the option to take its royalty share in kind or in value. There are many circumstances (e.g., low volume leases in remote areas, areas with capacity and infrastructure constraints) where taking royalties in-kind is certain to lose money.

Sec. 3(a)(2)--Ownership and Receipt by United States

This section provides that the Government shall not defer or delay receipt of production. Taken together with Sec. 3(c)(1), Effect of Tender by Lessee, Sec. 3(d)(3), Requirement to Take, and Sec. 6(a)(2)(B), Requirement to Resolve Imbalances, the Government will forfeit any production not taken within a certain time frame. (That time frame is 3 consecutive days within a calendar quarter.) This time frame is not realistic. Operating agreements are more commonly on a monthly basis.

The Government will lose title to and benefit of untaken royalty volumes under this Bill. This alters the intent and operations of lease terms. Lease terms require royalty on the full amount of production at the end of the month following the month of production; this bill requires the QMA to take royalty volumes on a daily basis. There will be instances where the Government or the QMA cannot accept its royalty share in such a timely manner and thus lose the benefit of the lease production. There will be cases where a QMA nominates transportation volumes (of royalty production) more than those actually produced and incur pipeline imbalance penalties. Conversely, there will be times when the delivered volumes of royalty production exceed the QMA nominated transportation volumes. If the QMA cannot otherwise sell the excess volume, the Government will be harmed by not benefiting from the value of that excess volume. It is not known whether the lessee, the operator, or the pipeline will take possession the excess production. The costs of these operational risks could be substantial and have always been the responsibility of the lessee, not the Federal Government.

> **H.R. 3334 imposes substantial operational risk on the Government.**
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> For example, the QMA may nominate 50,000 barrels of royalty oil for transportation when a lease actually produces 60,000 barrels of royalty oil. If the transporter does not accept the additional 10,000 barrels, and alternate transportation is unavailable, the Government will simply lose this amount under the Bill.

Also, the Government is at risk from QMA bankruptcy, etc. If the QMA can't take delivery, we may either lose the royalty share altogether or be forced to take and sell it at fire-sale prices. Finally, this section allows for surface storage only. Much storage is sub-surface.

Sec. 3(a)(3)--Selection of and Contracts with a Qualified Marketing Agent

Paragraph (A) of this section provides that the Secretary shall contract with a person to act as a QMA for "each lease premises." While this language is ambiguous, it appears that we would have to arrange for a QMA on a lease-by-lease basis. Paragraph (C) provides that the Secretary shall contract with not more than one QMA for each lease premises for each oil and gas product. These requirements have a potentially large administrative burden if individual contracts must be let for each of the more than 20,000 Federal oil and gas leases for each oil and gas product, as the legislation suggests. They would require potentially two, and different, QMA's per lease in those many cases where both oil and gas is produced--creating a huge administrative burden. It would be less of a burden if leases and products could be aggregated (i.e., one QMA for each field or area). MMS would still require an audit staff to audit both QMA's and lessees. In effect, the Government will exchange one administrative operation for another.

Furthermore, the language restricts our ability to determine the best means to dispose of royalty production -- it prohibits competitive sale at the lease, restricts our ability to transfer to other Federal agencies (as Texas does with State royalty gas), and prevents us from transferring it to the Strategic Petroleum Reserve or marketing it through another mechanism. In short, it requires we always use, and pay, a middleman, even when a middleman would add no value.

> H.R. 3334 prohibits the Government from transferring gas to other governmental facilities as Texas has found beneficial in its RIK program.

Paragraph (B) of this section sets the qualifications for the QMA. Although the Secretary has the option of rejecting any person to act as a QMA by reason of affiliation with downstream service providers, the Bill does not prohibit lessees or their affiliates from being QMA's. It can be reasonably expected that in most cases the only available QMA will be affiliated to some degree with either or both the lessee, field operator, or downstream service providers, as these are the entities that already have in place the infrastructure to move and dispose of the production. As discussed in the comments on the definition of affiliate, the Bill does not provide safeguards against price manipulation between QMA's and their affiliates.

Paragraph (D) provides that QMA's will be selected by competitive bid, which is a procurement term of art usually applied to sealed bids in which the differing quality of offers cannot be considered. The kind of services to be provided by marketing agents are typically procured though requests for proposals that are evaluated for quality and other factors. Selection and monitoring of QMA's will create administrative costs the Government currently doesn't have -- costs that have not been accounted for in the Department's $7.3 million estimate of administrative cost savings from the Bill (see section D.1. of this report). Furthermore, the Bill doesn't address the number of bids needed to qualify the bidding process as competitive or give criteria for minimum bid amounts. It also doesn't say how the Government is to dispose of its royalty production for leases that receive no or inadequate bids from QMA's; the Government could easily lose access to its royalty volumes in these situations.

Paragraphs (E) and (F) of this section provide in combination that the Government will compensate the QMA directly from the proceeds derived from the sale of production. The Government will absorb all marketing costs that are now the implied duty of the lessee and, other than through contract terms, the Government has no safeguards against QMA's cost overruns.

Paragraph (G) requires the QMA to dispose of the royalty production in an open and competitive manner, but prohibits the QMA from precluding disposition to any person by reason of affiliation. (See also paragraph (B).) The Bill does not, and likely cannot, assure against manipulation of prices in affiliated transactions.

H.R. 3334 permits producers' affiliates to serve as QMAs.

This is not permitted in the Alberta RIK program.

Sec. 3(a)(4)--Transportation Costs

This section requires the Government to bear all transportation costs. In those cases where the transporter is affiliated with the lessee, current regulations require that the transportation allowance be based on the transporter's actual costs. Under this Bill, the Government will incur higher transportation costs by virtue of being charged rates that incorporate elements currently disallowed, such as excessive return rates or other costs not directly attributable to transportation. Higher transportation costs in turn mean lower revenues to the Federal Government. More detail on the impacts of this provision are contained in comments on Sections 4 and 5.

This section would mandate that the contract with the QMA include a provision that the Government bear the costs of transportation. By doing so, it removes any liability by the

QMA for transportation and transfers the operational risks associated with transportation to the Government. The Government should have the flexibility to determine the most appropriate contract with the QMA.

Sec. 3(a)(5)--Processing Costs

This section requires the Government to bear all processing costs. In those cases where the processor is affiliated with the lessee, current regulations require that the processing allowance be based on the processor's actual costs. Actual costs are commonly 10 to 20 percent less than third party charges, but can be as little as one-half of what processors charge third parties for processing services. It is doubtful that QMA's can negotiate rates that are lower than those charged to third parties. Accordingly, the Government will incur higher processing costs under this Bill. MMS currently recognizes about $38 million per year in processing allowances. We estimate the Government would incur an additional $4 million to $8 million per year in processing costs under this Bill.

Not only is it doubtful that the QMA can negotiate rates lower than those charged by third parties, the QMA may have no choice for processing and be subject to monopolistic charges by the processor.

As discussed in the comments on the marketable condition definition, certain field services now considered part of putting the product in marketable condition would be considered processing under this bill. The Government would pay third party costs for services in which the Government has never shared.

This section would mandate that the contract with the QMA include a provision that the Government bear the costs of processing. By doing so,

LaBarge Project Royalty Revenues Decline to Zero With RIK

A major oil company produces gas from several Federal unit agreements in Wyoming and moves the raw gas stream about 40 miles from the field to its Manufacturing Facility where carbon dioxide and sulfur are recovered. The producer owns the carbon dioxide pipelines that move the carbon dioxide to Rock Springs and Bairoil, Wyoming and the railroad spur that move the sulfur to Opal, Wyoming. The QMA would have no choices for processing. It must purchase processing from the facility because there are no other facilities to process the gas. The QMA would also have to use the producer's transportation systems for the carbon dioxide and the sulfur. Given the complete monopolization of the facilities by the producer, it could charge rates for transportation and processing that would exceed the sales receipts of the products sold by the QMA. No QMA would bid on the contract, except the producer. The producer is currently marketing the product at no cost to the taxpayer.

Current annual royalties of $4.3 million would disappear for this project alone.

it removes any liability by the QMA for processing. The Government should have the flexibility to determine the most appropriate contract with the QMA.

Sec. 3(a)(7)--Fair Market Value Requirements

This section defines the net proceeds received from the sale of royalty production as fair market value. It does not define "net proceeds," so one must assume that "net proceeds" means net of QMA and all other costs. The definition differs significantly from the definition of fair market value contained in current statute and lease agreements.

Sec. 3(b)--Rights, Obligations, and Responsibilities of States

Sec. 3(b)(1)--Selection of Qualified Marketing Agents

This section provides an option for States to act on behalf of the Government in selecting QMA's. Under paragraph (4), a State electing this option would have to administer the program for all Federal oil and gas production in the State.

The Bill is silent on the implications of a State not fulfilling all of the Federal obligations of this proposed legislation and other applicable statutes. The Government will either have to assume that risk or incur costs of oversight responsibilities of a State's operations. Because the Bill does not authorize a State to collect monies from the QMA, MMS will still have to collect and distribute the royalties. Any administrative savings are questionable.

The Bill does not exempt State procurements from the Federal acquisition rules explicitly and it is uncertain whether a procurement by a State on behalf of itself and the U.S. would be exempt. The States can pull out of this arrangement with only 180 days notice, which might not be sufficient to give the U.S. time to select a new marketing agent under competitive conditions.

Sec. 3(b)(6)--Limitation on Deductions from State Share of Receipts

This section provides that the State's share of receipts for the sale of royalty production will be made without any deductions of receipts under the net receipt sharing provisions of the Mineral Leasing Act. The Bill is unclear on whether the Government or the State will fund a State's administration of a RIK program. In any event, States' participation in this arena will create another level of oversight administration and accounting for the Government. If all States exercise this right, Treasury loses $6.2 million (FY98 Net Receipts Sharing deductions).

Sec. 3(c)--Rights, Obligations, and Responsibilities of the Lessee

Sec. 3(c)(1)--Effect of Tender by Lessee

This section provides that the lessee shall tender royalty production to the Government at the delivery point for each lease. If the Government fails to take the entire volume tendered, the lessee's duty is nonetheless satisfied. As discussed under Sec. 3(a)(2), the Government will lose the benefit of royalty volumes produced but not taken. (See also Sec. 3(d)(3) below.) While, we believe these costs could be substantial, we have not attempted to quantify those direct revenue losses in this analysis.

Sec. 3(c)(2)--Measurement of Lease Production

This section requires the lessee to measure lease production. It does not indicate whether that production is in marketable condition as contemplated by the current regulations. It indicates the Government will incur much of the costs of cleaning, treating, sweetening, and conditioning that are now the responsibility of the lessee. It also indicates that the Government will incur costs of transporting non-royalty-bearing substances, such a water, that are not currently an obligation of the Government. (See also Sec. 4(b) below.)

Sec. 3(d)--Rights, Obligations, and Responsibilities of Qualified Marketing Agents

Sec. 3(d)(1)--In General

This section authorizes QMA's to enter into sales, transportation, and processing agreements on behalf of the Government. The Government will have to develop rules to oversee QMA's. Disputes can be expected to arise between the Government and QMA's over execution of contracts.

Under Sec. 9 of the Bill, QMA's will report to the Government the royalty quantities received; lessees will report royalty volumes produced. This raises a question as to who is responsible for resolving differences between QMA and lessee reports and whether the Government can accurately monitor imbalances.

> There are currently about 3,600 leases and agreements that qualify for stripper royalty rate reduction (i.e., with wells averaging less than 15 barrels per day). Roughly 70 percent of those properties are located in New Mexico and Wyoming. The Government would have to either accept delivery of the royalty on each of these leases each day or forgo delivery altogether. With a annual royalty portion of about 1,492,000 barrels from all stripper wells, at $15.50 per barrel, the Government could stand to lose up to $23 million each year.

Sec. 3(d)(3)--Requirement to Take

This section requires the QMA to take 100 percent of the royalty share tendered by the lessee from each lease premises on a *daily* basis. As discussed under Sec. 3(a)(2) above, it may not be advantageous or even realistic to take production when produced, particularly on a daily basis. Daily taking can realistically be accomplished only when the lease production is physically connected to a pipeline. For stripper leases, it may take months of production to acquire a sufficient quantity of royalty oil to make it worthwhile to transfer to a QMA and thus to market. The QMA may not be able to efficiently aggregate small amounts of production and sell them at an enhanced price, as contemplated by the Bill.

Sec. 3(d)(4)--Enhancement of Revenues to the United States

This section encourages a QMA to enhance royalty revenues by seeking opportunities for the sale of royalty production away from the lease. This is the only provision of the Bill that provides opportunities for increased revenues over a royalty-in-value system, but does not add any value over existing law. The Bill presumes that QMA's can and will, more often than not, perform better than oil and gas companies or their affiliated marketers. Enhancement requires opportunities for aggregation and downstream sales. It implies that any uplift in value gained by these opportunities will be greater than (will not be offset by) the incurred costs. As discussed elsewhere in this analysis, it is doubtful that QMA's can negotiate lower service charges than what the Government already recognizes in allowances, particularly for affiliated, non-arm's-length transportation and processing. In fact, the Bill will increase many of the transportation costs incurred by the Government. Coupled with the provisions that 40 percent of royalty oil must be offered to eligible small refiners at the lowest prices, and that require daily acceptance of marginal production, the likelihood of revenue enhancement becomes implausible.

Sec. 3(d)(5)--Affiliate Transactions

This section establishes a "Code of Conduct" governing sales transactions between the QMA and itself or an affiliate. The same comments regarding oversight rules and settlement of controversies given in Sec. 3(d)(1) apply here. Litigation will arise over issues related to QMA-affiliate transactions.

4. SEC. 4. COSTS RESPONSIBILITY

A detailed analysis of the revenue impacts of this section of the Bill is contained in Part E., Direct Revenue Impacts, of this report.

Sec. 4(a). Merchantable Condition

This section provides that the lessee will bear all costs of placing the royalty production in merchantable condition at the royalty delivery point; responsibilities for the costs for gathering and transportation are not dependent upon whether the production is in marketable condition. However, given the definitions of "merchantable/marketable condition" and "processing/process" in Secs. 2(18) and 2(25), respectively, and how they differ from their current applications under the regulations, the Bill will have the Government incur costs of treating and conditioning which are now the responsibility of the lessee. The cost/revenue impact of this provision is $85.2 million to $177.9 million per year based on the percentage of Federal gas production requiring treatment and the typical range of costs for such treatment. (See discussion under E.1.a.)

Sec. 4(b)--Gathering and Transportation of Royalty Oil and Royalty Gas

Paragraph (1) of this section places the responsibility of gathering royalty production solely on the lessee. Paragraph (2) requires the Government to bear all costs of transporting royalty production *to and beyond* the delivery point. The Bill defines "transportation" as (1) the movement of unseparated, bulk production away from the lease to a point distant from the lease and (2) the movement of separate, identifiable production away from a *well* on the lease to any point not on the lease. The Bill defines gathering as the movement of production to a central accumulation point.

The current rules define "gathering" as the movement of lease production to an approved central accumulation or treatment point; gathering costs are the sole responsibility of the lessee. In practice, transportation, for which the lessee is permitted an allowance, is downstream of the royalty measurement point. Under the Bill, the delivery point will likely equate to the royalty measurement point. Because the Government will bear all costs of transporting royalty production to and beyond the delivery point, the Bill will shift to the Government much of what are now considered gathering costs. Because the distinction between gathering and transportation under the Bill is ambiguous, most, if not all, movement downstream of the well can be classified as transportation, meaning the Government will incur considerable transportation costs back to the wellhead.

Because "transportation" includes the movement of unseparated, bulk production away from the lease, the Government will also incur costs to move non-royalty bearing substances, such as water, away from the lease/wellhead. There are five readily obvious cases, and probably others, in which this would apply. Those cases are described in detail in Section E.1.c. of this report.

H.R. 3334 requires the Government to pay for moving bulk production away from the lease.

For example, approximately 123,000 barrels of oil are produced daily from the Mensa Field in the Gulf of Mexico. However, approximately 7,500,000 barrels of bulk production are moved annually from the subsea completion to the royalty meter off the lease. The increased costs to the Government of moving this bulk production ($0.23/bbl to $0.69/bbl) on this one field alone are $1.8 million to $5.1 million per year.

The cost/revenue impact of the gathering costs and the costs of moving bulk production is estimated at $13.2 million to $41.5 million per year. This revenue loss will increase substantially as industry develops more deep water plays. More detail on these estimates is provided in the Section E.1.c. of this report.

Sec. 4(c)--Limitation on Lessee's Responsibility for Costs

This section requires the Government to bear all costs of disposing and marketing its royalty share of production. It shifts all marketing costs to the Government and contravenes the lessee's implied covenant to market the production to the mutual benefit of lessee and lessor. The QMA will incur these costs and pass them back to the Government in the form of reduced revenue. Ironically, the Bill would actually create new marketing costs (to be borne by the U.S.) in the many cases where there are currently no such costs, i.e., for the substantial volumes of crude oil production simply moved from major producers to their own refineries.

The estimated cost to the Government for marketing services is $17 million to $45.5 million per year. (See discussion under E.1.d. of this report.)

Sec. 4(d)--Reimbursement of Costs

This section requires the Government to reimburse the lessee for transportation costs; the reimbursements will be taken from the Government's net proceeds. Besides the direct financial costs to the Government, addressed in Sec. 4(b) above and Sec. 5 below, this provision will require a certain level of administration to account for the reimbursements, including adjustments to State receipts, and to audit the costs on which they are based. We did not attempt to quantify these increased administrative costs and therefore they are not included as an offset to the $7.3 million estimated administrative cost savings of the Bill.

5. SEC. 5. TRANSPORTER CHARGES

Sec. 5(b)--Reimbursement for Transportation Costs Prior to the Delivery Point

> **H.R. 3334 shifts the cost of moving bulk production to the Government.**
>
> Transportation of bulk production from a subsea tie-in to a platform off the lease where the royalty meter is located, such as Mensa, would be considered transportation under H.R. 3334, whereas under current rules it would be gathering. OMM field experts expect that the majority of projects coming on-line will be subsea which means that bulk production movement is markedly increasing.

This section prescribes the methods to calculate reimbursements to the lessee or its transporting affiliate for the costs of transporting production prior to the delivery point. Current regulations permit a transportation allowance to move production from the lease, which is generally the point of royalty measurement, to a point of sale or royalty valuation off the lease. All costs associated with gathering production to the royalty measurement point are the sole responsibility of the lessee. Because the royalty measurement point equates to the delivery point under the Bill, the Bill will require the Government to pay for gathering costs. The amount of the gathering costs and the costs of moving bulk production is estimated at $13.2 million to $41.5 million per year. (More detail on these estimates is provided in the Section E.1.c. of this report.)

Sec. 5(b)(1)--Transport by Regulated Pipeline or Facility

The reimbursement for the lessee's costs of transporting royalty production through a regulated pipeline or facility before the delivery point would be (A) the actual tariff charges for nonaffiliated transactions, or (B) the lower of the tariff rate or actual rate paid under the tariff for affiliated transactions.

Most predelivery-point gathering systems are owned by lessees, field operators, or joint ventures formed by lessees. Current regulations normally require lessees to use their actual transportation costs; tariff rates are generally higher than actual costs.

Sec. 5(b)(2)--Transport by Shipment-by-Shipment Tariff Jurisdiction Pipeline/Facility

The same comments as in Sec. 5(b)(1) apply to this provision.

The Texas RIK program, unlike H.R. 3334, requires producers to transport RIK at no cost to the Government.

Sec. 5(b)(3)--Transport by Unregulated Pipeline or Facility

Paragraph (A)(ii) sets the rules for determining transportation reimbursements for shipment on unregulated, affiliated pipelines and facilities prior to the delivery point as either (I) the weighted average (by volume) of third party charges if third party production is being transported through the facilities, or (II) if no third party production is moved through the facilities, the facility owner's costs of operating the facility, including a return on capital investment, as calculated under Sec. 5(b)(3)(B). Current regulations require the costs of transportation on unregulated, affiliated pipelines to be calculated based on the pipelines' actual costs.

Sec. 5(b)(3)(B)

This section establishes operating costs as the sum of the direct operating, maintenance, and repair expenses; indirect costs, or overhead, allocated to the facility, not to exceed 15 percent of direct costs; and an allowance for capital investment as either (1) depreciation and return on undepreciated capital or (2) a return on depreciable investment, with a rate of return equal to twice (2 x) Standard and Poor's industrial BBB bond rate.

These rules mimic those in the current regulations for determining non-arm's-length transportation allowances, except the current rules specify that depreciation is by the straight-line method based on the life of the reserves and the rate of return on investments is (1 x) the industrial BBB bond rate.

The Bill permits the return on depreciable investment method (method 2) that is currently limited to facilities placed into operation on or after March 1, 1988. The Bill has no such limit and in fact would permit lessees to switch from one method to the other in order to maximize costs and enjoy the benefit of a return on investment long after the facilities are fully depreciated.

Lessees currently cannot switch from one method to the other, without MMS approval, once they have made an election. The depreciation method results in higher returns than the return-on-investment method during the early stages of depreciation. However, as depreciation matures, the return-on-investment method begins to generate higher returns. Lessees will switch from the depreciation method to the return-on-investment method when the latter begins generating higher returns during the out years of depreciation. Because the return-on-investment method does not terminate at the end of depreciation, lessees will elect this method to continue claiming a return on investment after the assets are fully depreciated.

Both capital allowance methods would use a rate of return equal to 2 times the Standard and Poor's industrial BBB bond rating. Proponents supporting 2 x BBB cite the geothermal regulations published on November 8, 1991 (56 FR 57265), which provide that rate of return for capital investment in geothermal powerplants and transmission lines. MMS carefully examined various return rates in deliberating the current oil and gas valuation rules and determined that 1 x BBB adequately recognizes the cost of capital and the risks associated with constructing oil and gas transportation facilities. There is no sound basis for doubling this rate.

It is not appropriate to apply the reasoning behind the geothermal rule to the cost of financing oil and gas transportation facilities. The risk of investment is much greater for geothermal power projects because geothermal reserves are not as easily estimated or as dependable as oil and gas reserves. Because of the risks associated with production sustainability, financing costs for geothermal projects are inherently greater than those for financing oil and gas transportation systems. As explained in the geothermal rulemaking, equity financing may account for more than 50 percent of the capital invested in geothermal power projects and the required return on equity may be as high as 40 percent. Therefore, the weighted average cost of capital is easily greater than the straight corporate bond rate. MMS determined that the total cost of financing typical geothermal power projects approximates twice the BBB bond rate.

What is a reasonable return on investment?

H.R. 3334 would require the Federal Government to pay over 16 percent return on investment when it is required to use a lessee's or its affiliate's pipeline to transport oil or gas when that lessee doesn't normally provide third party transportation.

This is twice the rate that a major integrated oil company must pay today to borrow money in the bond market.

The projected costs owing to application of the return-on-investment method ranges from $6.2 million to $12.4 million per year. The projected costs owing to the increased rate of return ranges from $9.2 million to $18.5 million per year. These costs would be in addition to those recognized under the current allowance structure. (These estimates are explained in more detail in Section E.1.e. of this report.)

Sec. 5(b)(4)--Allowance of Higher Transportation Costs

This section allows for a higher rate of return for deep water (greater than 200 meters) transportation facilities. Deep water leases are currently allowed a royalty rate reduction to recognize greater costs and investment risks.

Sec. 5(c)--Charges for Transportation Costs Beyond the Delivery Point

This section establishes the rules for determining charges by the lessee or its affiliate for transporting royalty production through unregulated transportation facilities beyond the delivery point. In general, the rate will be negotiated as either (A) highest rate charged to a third party for transportation through the same facility or (B) the "fair commercial value" of the transportation services if no third party production is transported through the facilities. Paragraph (c)(2) provides that the standard used to determine "commercial value" will be based on the transportation services provided and not on ownership of the facilities.

It is not reasonable to legislate a highest rate for determining transportation charges, particularly without considering volume discounts. Doing so will maximize costs to the Government contrary to the Bill's stated purpose of enhancing royalties. Most transportation costs will probably be based on tariff rates. Should the transportation facilities be owned by the lessee or an affiliate, unregulated tariff rates will overstate the actual costs of transportation, as such facilities may serve captive, noncompetitive markets. In cases where there is no third party transportation, the Bill does not adequately describe how "commercial value" is to be determined.

The impact of using highest rates is not determinable. However, MMS found in its gas RIK pilot that the rates negotiated and paid by MMS's marketers for transportation through lessee- or affiliate-owned facilities were considerably higher than the actual costs allowed under the current regulations. When extrapolated to all RIK production for both oil and gas, the added costs to the Government for transporting through non-arm's-length facilities is estimated to range from $30 million to $45 million per year. The projected added costs of using tariffs in non-arm's-length transportation arrangements is about $12 million per year.

To the extent that lessees choose to pay royalties in kind for leases under Section 6 of the OCSLA (see footnote 1 on page 1.), the Bill would also have the Government pay for transportation for production from those leases. Depending on the lease's vintage, the terms for many Section 6 leases do not authorize the lessee to take transportation allowances; i.e., the transportation costs are now the sole responsibility of the lessee for these certain leases. Transportation from Section 6 OCS leases under this bill would cost the Government about $5.3 million per year in new expenses. (See explanation in section E.1.f. of this report.)

Sec. 5(d)--Arbitration

> The arbitration section requires that the results of arbitration be held in secret.

This section appears to be in anticipation of numerous disagreements arising over transportation costs, which raises questions about the legislation creating new controversies. It requires the U.S. to enter into binding arbitration to settle such disputes. We note that the U.S. can't name any State or Federal employee as an arbitrator unless the other party agrees. Section 5(d)(6), at 33. The arbitration section includes the incredible requirement that the parties cannot disclose the results of the arbitration. Section 5(d)(7), at 34. We cannot find any reasonable rationale for prohibiting the United States from disclosing the outcome of litigation that determines how much public money will be spent on non-national security matters.

6. SEC. 6. IMBALANCES

Imbalances are a common occurrence in today's oil and gas markets; they occur when marketers nominate different volumes for transportation or sale than are actually available from production. Since the Government has no control over the volumes produced this will be a particularly acute problem. Of particular note is paragraph (a)(2)(B), which, as discussed in Sec. 3(a)(2) above, states that the Government will forfeit royalty volumes if not taken.

MMS currently does not participate in imbalances because lease terms and regulations require royalty on the full volume of production measured during the month of production. Requiring the Government to participate in imbalances will deny the Government full and timely benefit of its allotted production.

Paragraphs (b)(2)(A)(i) and (ii) require operators to file royalty share imbalance reports within 60 days of the month of production or 60 days after receipt of information on actual quantities. However, the Bill does not provide for penalties for noncompliance should operators fail to report. Paragraph (d)(2) provides that imbalances may be paid in value or in kind, at the lessee's option at least within 60 days of the final imbalance report. When paid in value, the cash payment will be based on the net proceeds in terms of actual value received; no interest will accrue prior to the date of the settlement. These provisions will deny the Government benefit of its full royalty production for at least 120 days. Both Government and States will ultimately lose the time value of the royalty production. Furthermore, the settlements made at these late closure dates may not represent market value at the time of production.

Overall, the imbalance provisions of this section are biased heavily in favor of the producer. First, the government is penalized if the QMA fails to take full volumes for greater than three consecutive days per quarter. There is no similar penalty for a producer's failure to deliver. Second, the operator decides when to settle imbalances (Section 6(c)), when it owes the Government, and how to pay. Additionally, the imbalance provisions of this Bill will require yet another layer of administration to perform imbalance accounting and litigation costs to resolve disputes. The cost of these imbalances to the Government is unknown.

Imbalance Provisions Favor Producers

In February 1996, natural gas spot prices spiked to $15/MMBtu for a few days. Under H.R. 3334, producers would be able to keep 100% of their production during such a price spike, and settle days or weeks later when the price was back to $2.75 - 3.00/MMBtu. The Government would lose all revenues from price spikes, and could be faced with penalties from transporters if the QMA didn't use its contracted capacity due to the producer's failure to deliver.

7. SEC. 7. ROYALTY-IN-KIND FOR TRUCKED, TANKERED, OR BARGED OIL OR GAS

This section recognizes that not all production from Federal leases is connected to a pipeline for transportation to the first sale. It requires the QMA to select and utilize a transporter who is already transporting production from the lease premises. It prohibits competition from outside transporters or new transporters who wish to enter the market. The Government will not have the benefit of competitively priced transportation.

Crude oil reaching the surface is not generally in marketable condition. In a production area with more than one well, the oil flows from the wellhead to a centrally located facility where the impurities (basic sediment and water) are removed. Once the impurities are removed, the crude is ready to be measured for sale and transported to the refinery for processing. Onshore, where production volumes don't generally warrant the construction of pipelines, the oil is often stored at a tank battery located at the well site or treating facility. The oil collects in the tank until there are sufficient volumes to justify having a truck transport the oil to a pipeline interconnect or refinery.

There are many areas onshore where the above situation is the typical. For example, over 5,000 properties in the four onshore States of Colorado, New Mexico, Montana, and Wyoming produce less than 1 barrel of oil equivalent of royalty production per day. The San Juan Basin has over 1,900 producing leases and over 1,400 properties yielding about $5 million in oil royalties per year, mostly from wells producing less than one barrel of royalty oil per day. However, Section 3(d)(3) of the Bill requires the Government to take its share on a daily basis.

> **How Much is Enough?**
>
> In the San Juan Basin, 90 percent of the properties produce less than 1 barrel of royalty oil a day on an annual basis.
>
> **H.R. 3334 requires a QMA to accept one barrel of oil a day. It is unlikely the royalty would exceed the cost in this situation.**

This section covers many situations where RIK makes no sense for a lessor and where the lessor is at the mercy of the lessee. In situations involving small volumes of production in remote locations, the Government is at best entirely dependent on the producer for storage and transport to market. At worst, the Government could be forced to take a fraction of the small volumes and arrange to bring it to market separately, greatly increasing administrative costs and limiting the ability to aggregate. The expected cost of these requirements is unknown.

Section 7(c)(2) requires maintaining RSFA's provision for prepayment of royalties. However, section 3(a) says we must take all the royalties in kind unless otherwise provided in sec. 8. The Bill will in effect require the Government to take prepayments in-kind. It is difficult to see how that would be possible and might jeopardize small producers.

8. SEC. 8. LIMITATIONS ON APPLICATION

Pursuant to paragraph (a), the Bill does not apply to compensatory royalties, minimum royalties, and net profit share leases prior to payout. MMS would continue to manage these payments under an "in value" system.

9. SEC. 9. REPORTING

The administrative costs associated with this section of the Bill have been factored into the Department's $7.3 million estimated administrative cost savings as functions that would continue. (See explanation under D. of this report.)

10. SEC. 10. AUDIT

This section limits audits to lessees, QMA's, and nonaffiliated purchasers. It is inconsistent with Sec. 103(a) of the Federal Oil and Gas Royalty Management Act, which provides that any person transporting, purchasing, or selling Federal oil or gas shall make available to the Government such reports, records, or information to insure compliance with the Bill. The Government must have the authority to audit purchasers and transporters, whether or not they are affiliated with either the QMA and/or lessee, to ensure the Government is receiving full benefit for its royalty production. In the case of natural gas production, the audit authority must be extended to gas processors to assure the Government is receiving proper benefit for processed gas products and is not being overcharged for processing services. (See D. for more explanation of audit costs.)

11. SEC. 11. LEASE TERMS NOT AFFECTED

No comment.

12. SEC. 12. ELIGIBLE AND SMALL REFINERS

The small refiner provisions of the Bill severely limit the Government's ability to receive fair market value for 40 percent of royalty oil. First, each QMA is restricted to selling 40 percent of its oil to eligible refiners, oil that it might be able to get a better price for if it were allowed to market it. The current small refiner program does not require the Government to offer crude oil to eligible small refiners.

H.R. 3334 would require the Government to provide 40 percent of its oil to small refiners at the lowest offered prices.

Second, paragraph (a)(4) of this section establishes a pricing method based on the "lowest successful offers" for sales of royalty oil to eligible small refiners. The clear intent of this provision is to minimize the amounts small refiners will pay for oil. Minimizing the value of 40 percent of the Government's royalty oil is clearly contrary to the stated intent of the Bill to enhance royalties. (See also Sec. 2(7) above.)

Third, paragraph (b) limits the rate at which eligible small refiners may purchase oil from the eligible small refiner portion to not more than 60 percent of the combined distillation capacity of that eligible small refiner's currently operating refineries in the United States. To implement this paragraph and determine the eligible small refiner's current operating capacity, the Government will have to create and maintain a data base of all eligible small refiners' and their capacities. Such a data base will require periodic reporting by the eligible small refiners and an administrative staff to compile, input, and verify the reports.

Finally, Section 12(c) repeals the current administrative fees charged to eligible refiners, approximately $1 million per year.

13. SEC. 13. APPLICABLE LAWS

No comment.

14. SEC. 14. INDIAN LANDS

The Bill does not apply to Indian lands. However, MMS is concerned that legislation such as H.R. 3334 acts to economically de-value Indian leases relative to Federal leases, thus making Indian leases less competitive than their Federal counterparts. This is an issue of trust responsibility that is serious and uncertain in its effect.

15. SEC. 15. EFFECTIVE DATE; REGULATIONS

Paragraph (b) requires the Government to issue regulations implementing this Bill within one year after its effective date and to take all royalties in-kind starting 18 months plus one day after the date of enactment. One year to issue regulations implementing an Act of this magnitude and complexity is totally unrealistic. This Bill radically changes the way royalties are now recognized. Based on our past experience of issuing regulations, it will require two or more years to develop and issue implementing regulations. It may take longer to develop accounting systems to implement the Bill. Thus, from 18 months after enactment to the date all regulations and systems are perfected, the public's revenue is at substantial risk.

D. ADMINISTRATIVE COST IMPACTS

The Department estimates that after implementation of the legislation (beginning in FY 2000 at the earliest), the total administrative savings of H.R. 3334 would be no more than $7.3 million per year for the first 8 ½ years as described in detail below. In the latter half of the 9th year and beyond, administrative savings are expected to reach $24.4 million annually. Because the costs of operations, valuation, and audit functions are known with a high degree of certainty, actual savings can be determined with greater accuracy than other revenue impacts under the bill. New or additional administrative costs imposed by the Bill have not been included in this section's estimates.

1. Royalty Management Costs:

The MMS costs associated with the Royalty Management Program, for fiscal year 1997, were $83.4 million. This is comprised of RMP labor and support costs identified by function as follows:

Federal onshore and offshore oil and gas accounting and reporting	$16.0 million
Federal onshore and offshore oil and gas production & accounting verification	11.7
State and Federal oil and gas audit	33.0
Federal oil and gas valuation	2.4
SUBTOTAL - Costs associated with Federal oil and gas royalty collections	**$63.1 million**
Indian accounting, reporting, production & accounting verification, valuation and audit	15.9*
Solid minerals accounting and reporting, production & accounting verification, valuation and audit	4.4*
TOTAL	**$83.4 million**

*Functions associated with Indian and solid minerals (non oil and gas) leases are not subject to the provisions of this Bill.

The maximum administrative savings available, if all costs associated with Federal oil and gas royalty collections were eliminated, is $63.1 million. However, not all costs would be eliminated under the legislation. Certain functions and their associated costs would continue such as:

receiving payments and reports, accounting for and disbursing payments, and production verification. Most of the cost savings would be realized in Audit, while some administrative cost savings could be gained in Valuation, Production and Accounting Verification, and Accounting and Reporting. The savings in each area are explained below.

However, there would be new functions that would arise under the Bill whose costs would offset many of the identified savings. While their cost is unknown at this time, new functions would include selecting, monitoring, regulating, and auditing QMA's, managing transportation reimbursements, and overseeing other activities associated with a nationwide RIK program. There would also be an increase in costs for additional activities under some current functions, such as administering an expanded small refiner program.

2. Audit Savings:

State and Federal audit costs for oil and gas leases comprise $33 million of the total costs for Federal oil and gas royalty collections. Audits will continue for the next 7 years after the effective date of this Bill in accordance with the provisions of the Royalty Simplification and Fairness Act. Therefore, for the next 8 ½ years, MMS would continue to expend approximately $33 million ($4.6 million of these costs are paid to States with auditing agreements) to audit oil and gas royalties paid on Federal leases. After that period, we estimate that oil and gas audit **costs would be reduced by approximately $17.1 million.**

After enactment of RIK legislation, we would have to continue to audit QMA's, non-affiliated purchasers, and small refiners. Audit resources would also be used to analyze current marketing trends, audit and evaluate our QMA's accomplishments by comparing one to another and possibly comparing our QMA's accomplishments or yields to what the lessees are realizing in value for their portion of the Federal production, and determine the reasonableness of transportation and processing costs. **Therefore, for the 7 years immediately following enactment, audit costs would actually increase from current levels for auditing and evaluating QMA activities.**

3. Litigation savings:

The cost of litigation includes administrative and judicial reviews and support by MMS personnel of those processes. MMS costs are included in the total costs above, but are not separately identified. Additional costs (not identified here) are incurred by the Solicitor's Office and the Department of Justice. Virtually all of the litigation costs are incurred as a result of audit; that is, after an audit has been performed. Litigation costs are anticipated to continue for 3 or more years after the audits are completed, or a minimum of 11 years after the proposed legislation is enacted. Within DOI a potential savings of 2 to 3 staff years ($180k to $270k) may occur within the Office of the Solicitor after 11 years on existing royalty claims. Costs related to MMS' Division of Appeals are part of support costs and are included in the total costs identified for each function in the preceding table. Therefore, as costs for those activities are reduced the related appeals costs are reduced proportionately.

However, it is likely that litigation would increase under H.R. 3334. The Bill places DOI in the position of relying on various marketing entities, most of whom will have a serious conflict of interest because they are affiliated with producers who are typically opposed to DOI on royalty issues. Litigation would arise over issues such as when deliveries and imbalances must be taken, as well as over marketers' decisions made in conflict of interest situations, because the marketing entity that DOI must use will favor the producer that it is affiliated with. With the uncertainty and the extended time frame for any feasible savings under litigation, savings impacts are excluded for this analysis.

4. Operations and Valuation Savings:

Excluding Federal oil and gas audit, Indian, and other minerals costs leaves a maximum annual amount of $30.1 million in MMS costs associated with accounting and reporting, production and accounting verification, and valuation activities.

Of these costs, **we estimate a savings of $7.3 million** with an extensive RIK program.

Under the bill, some of the functions under Accounting and Reporting, Production and Accounting Verification, and Valuation would be eliminated or reduced and savings would be realized. For example, under Accounting and Reporting, the collection of payor data for leases would decrease as would accounting for royalty payments and comparing the payments to the payment reports for a savings of about 20 percent. However, there may be some offset in the savings for increased needs in other Accounting and Reporting areas such as administering the small refiner program. Front-end processes such as processing reports, correcting reporting errors, general ledger accounting and the collecting of basic lease, well, and unit agreement data will not significantly change.

Reductions in Production and Accounting Verification will save about 30 percent, mainly as a result of processing fewer royalty reporting discrepancies for transportation and processing allowances and interest calculations under RSFA. Comparisons of sales volumes to production volumes would continue as would verification of proper oil and condensate volume reporting and gas volume reporting by operators, and stripper-well qualification verifications. MMS would also continue processing all Indian royalty payments and royalty rate discrepancies.

Savings in Federal oil and gas valuation labor costs would be approximately 80 percent and would be attributed to reductions in approving exceptions to standard transportation and processing allowances, issuing oil and gas valuation guidance, and developing oil and gas valuation regulations. Remaining functions would include: compensatory royalty valuation guidance, solid mineral and Indian mineral valuation guidance, regulation of net profit share leases (including providing guidance and receiving and maintaining reports), review of transportation costs under section 5 (b) (4) of the Bill, and technical and operational assistance for the nationwide RIK program.

In the first 8 ½ years after enactment, the total estimated annual savings from an extensive RIK program will be at maximum $7.3 million. However even with a nationwide RIK program there will be functions performed by the MMS to administer the RIK program, **so actual savings will be less.**

Under Net Receipts Sharing, the states are charged a portion of the costs associated with the onshore portion of the Royalty Management Program. In fiscal year 1998, the states are charged about $6.2 million for administering the Royalty Management Program. This charge to the states results in increased revenues to the Federal government. Under Section 3 (b) (6) of the proposed legislation, a state choosing to administer the RIK program would not be charged for the services it provides under Net Receipts Sharing. **If all states accepted this provision, then receipts to the Federal government would be reduced for the cost of those services up to a maximum of $6.2 million, offsetting the potential administrative savings to the Federal government.**

5. Summary

In summary, for the first 8 ½ years after implementation of the legislation (beginning in FY 2000 at the earliest), the total administrative savings would be no more than $7.3 million per year. Reductions in audit costs would begin to occur in the latter half of the 9th year, pushing the total cost savings to approximately $24.4 million ($17.1 million in audit + $7.3 million in operations and valuation costs). Litigation cost savings, if realized at all, wouldn't occur until about 11 or more years after enactment. Some lost revenue from Net Receipts Sharing, ranging from $0 to as much as $6.2 million per year, would occur depending on the extent of RIK functions and other RMP functions assumed by states. Finally, some new costs would be incurred to administer and oversee an effective nationwide RIK program and the costs to operate expanded programs under the Bill would increase. These costs have yet to be quantified.

The following table shows the current administrative and audit costs of RMP and the effects of the bill for the first 8 ½ years of enactment and after that period.

Royalty Functions	Current 1997 Costs	Annual Costs First 8 ½ Years	Annual Costs After 8 ½ Years
Federal onshore and offshore oil and gas accounting and reporting	$16.0 million	$12.8 million	$12.8 million
Federal onshore and offshore oil and gas production & accounting verification	11.7	8.8	8.8
State and Federal oil and gas audit	33.0	33.0	15.9
Federal oil and gas valuation	2.4	1.2	1.2
SUBTOTAL - Costs associated with Federal oil and gas royalty collections	**63.1**	**55.8**	**38.7**
Indian accounting, reporting, production & accounting verification, valuation and audit	15.9	15.9	15.9
Solid minerals accounting and reporting, production & accounting verification, valuation and audit	4.4	4.4	4.4
TOTALS	**$ 83.4 million**	**$ 76.1 million**	**$59.0 million**
MAXIMUM POTENTIAL SAVINGS		**$ 7.3 million***	**$24.4 million***

*Because there will be additional functions performed by the MMS to administer a nationwide RIK program, **actual savings will be less.**

E. DIRECT REVENUE EFFECTS

1. Additional Royalty Costs

a. Secs. 2(18) and 2(25) --"Marketable condition"

Under the proposed legislation, the Government will pay the costs of sweetening, treating, and conditioning the RIK production for market. This will primarily impact royalties on natural gas, which commonly requires the removal of acid gas contaminants--predominantly H_2S--to place the gas in marketable condition. (The removal of acid gases--H_2S and CO_2--is commonly called sweetening. Sweetening, treating, and conditioning, as used here, are synonymous.)

Most pipelines accept gas containing 4 ppm H_2S (Tannehill and Dorsett, 1994). Frequency distributions given in Tannehill and Dorsett (1994) indicate that 44 percent of gas in the Lower 48 states requires H_2S removal. Tannehill and Dorsett (1994) indicate that H_2S removal/recovery costs typically range between 0.18/Mcf and 0.38/Mcf. Accordingly, the projected annual costs to the Government for H_2S removal, based on 1996 royalty volumes, are calculated as:

Conventional gas

	Royalty volumes (10^6 Mcf)	Volumes requiring treatment (10^6 Mcf)	Treatment costs (10^6 \$)
Onshore	169.0	74.4	13.4-28.3
Offshore	837.4	368.5	66.3-140.0

These estimates include only the costs of removing H_2S from conventional, non-coalbed methane gas. There might be some additional costs for removing CO_2 from these gas streams.

For coalbed methane in the San Juan Basin, CO_2 removal costs range between \$0.08/Mcf and \$0.14/Mcf. Therefore, the projected annual costs to the Government for treating coalbed methane would be:

Coalbed methane

	Royalty volumes (10^6 Mcf)	Volumes requiring CO_2 removal (10^6 Mcf)	CO_2 removal costs (10^6 \$)
Onshore	68.5	68.5	5.5-9.6

The total projected reduced royalty revenue attributable to treatment costs is \$85.2 million to \$177.9 million per year.

References

Tannehill, C.C., and Dorsett, L.R., 1994, Gas processing and transportation extraordinary cost allowance analysis, Madden Deep gas, Fremont County, Wyoming: Purvin & Gertz, Inc., proprietary report prepared for Louisiana Land & Exploration Company, p.94.

U.S. Department of the Interior, Minerals Management Service, Mineral Revenues 1996.

b. Section (3)(a)(5) - "Processing costs "

Section 3(a)(5) requires the Government to bear all processing costs. In those cases where the processor is affiliated with the lessee, current regulations require that the processing allowance be based on the processor's actual costs. Actual costs are commonly 10 percent to 20 percent less than third party charges, but can be as little as one-half of what processors charge third parties for processing services. It is doubtful that QMA's can negotiate rates that are lower than those charged to third parties. Accordingly, the Government will incur higher processing costs under this Bill.

MMS currently incurs about $38 million per year in processing allowances. **We estimate the Government would incur an additional $4 million to $8 million per year in processing costs under this Bill.**

c. Sec. 4(b)--Gathering and transportation cost responsibility

The proposed legislation places the costs of gathering RIK production solely on the lessee. However, it also has the Government bearing all costs of transporting the RIK production **to and beyond** the delivery point until disposition. In effect, the Government will incur much of the gathering costs it now disallows.

Gathering costs will have a significant negative impact on royalty revenue. However, this issue needs thorough analysis to fully understand the magnitude of the impact. A review of existing contracts indicates that it costs $0.01/Mcf to $0.10/Mcf to gather gas. Field experts with the Offshore Minerals Management and the Bureau of Land Management estimate that approximately 10 percent of offshore gas production, and 25 percent of onshore gas, is separated at the well but is measured for royalty purposes downstream of the well (onshore for OCS leases). Such movement under the current regulations is considered nonallowable gathering, but would be allowable as transportation under the proposed legislation. Given these numbers, the reduction in gas royalties would be:

	Royalty volumes (10^6 Mcf)	Gathered volumes (10^6 Mcf)	Cost at \$0.01/Mcf (10^6\$)	Cost at \$0.10/Mcf (10^6\$)
Onshore gas	237.5	59.4	0.6	6.0
Offshore gas	837.4	83.7	0.8	8.4

A brief review of oil pipeline tariff rates shows that gathering charges for oil ranges from about $0.06/bbl to over $0.90/bbl and typically ranges between $0.23/bbl and $0.69/bbl. Field experts with Offshore Minerals Management and the Bureau of Land Management estimate that approximately 25 percent of offshore oil and 50 percent of onshore oil is separated at the well but measured for royalty purposes downstream. Such movement under the current regulations is considered nonallowable gathering but would be allowable as transportation under the proposed legislation. Accordingly, the reduction in oil royalties for gathering charges would be:

	Royalty volumes (10^6 bbl)	Gathered volumes (10^6 bbl)	Cost at \$0.23/bbl (10^6\$)	Cost at \$0.69/bbl (10^6\$)
Onshore oil	15.2	7.6	1.8	5.2
Offshore oil	73.0	18.3	4.2	12.6

By including the movement of “unseparated bulk production” in the definition of transportation, the Government will also incur costs of moving nonroyalty bearing substances, such as water and other waste products, that are now disallowed. Below are five examples, and there are certainly others, in which this would apply:

1. In the Grand Isle system, there is approximately 40 percent water shipped with the oil. The cost to move this nonroyalty-bearing water is approximately $1 million per year.

2. Oil from certain offshore California leases is shipped with approximately 20 percent water. The cost to move this nonroyalty-bearing water is approximately $1.3 million per year (total cost of $6.6 million x 0.20).

3. Gas analysis show that the coalbed methane from the San Juan Basin, New Mexico, contains 10 percent CO_2. Under the current regulations, the Government shares in the costs of transporting 2 percent CO_2. Transportation of the other 8 percent CO_2 is currently nonallowable. The proposed legislation would require the Government to pay to transport the 8 percent CO_2. The cost is approximately $1 million to $1.2 million.

4. Approximately 46,000,000 Mcf are produced annually from the Popeye field. The costs to move the bulk production from the subsea manifold to the Cougar Platform are $.09/Mcf which is an increased annual cost of approximately $700,000 to the Government.

5. Approximately 123,000 bbls. are produced daily from the Mensa Field. This means that approximately 7,500,000 barrels of bulk production are moved from the subsea completion to the royalty meter off the lease. The increased costs to the Government of moving this bulk production ($0.23/bbl to $0.69/bbl) are $1.8 million to $5.1 million per year.

Transportation of bulk production from a subsea tie-in to a platform off the lease where the royalty meter is located, is considered gathering. OMM field experts stated that most projects coming on-line are subsea which means that bulk production movement is increasing.

The total increased annual costs to the Government for just these five examples are $5.8 million to $9.3 million.

Projected reduced royalties owing to gathering costs and transportation of nonroyalty-bearing substances could be as much as $13.2 million to $41.5 million per year.

<u>References</u>

Oil Price Information Service, 1997, Interstate pipeline rates on crude petroleum products.

Oil Price Information Service, 1997, Intrastate pipe line rates on crude petroleum oil.

d. Sec. 4(c)--Marketing costs

Under the proposed legislation, the Government will indirectly bear all costs associated with marketing the RIK production. The QMA will initially incur these costs and pass them to the Government in the form of net payments, which, under proposed Sec. 3(a)(7), will equate to fair market value. MMS currently disallows marketing costs as a deduction.

Prior studies indicate that marketing fees for gas average between $0.01/MMBtu and $0.03/MMBtu. Equating an MMBtu to an Mcf, the projected marketing costs to the Government using 1996 gas royalty volumes are:

	Royalty volumes (10^6 Mcf)	Cost at $0.01/Mcf ($10^6$$)	Cost at $0.03/Mcf ($10^6$$)
Onshore gas	237.5	2.4	7.1
Offshore gas	837.4	8.4	25.1

In comments made at public workshops, representatives of the petroleum industry indicated that marketing costs for oil range from \$0.07/bbl to \$0.15/bbl[2]. Accordingly, the projected marketing costs to the Government using 1996 oil royalty volumes are:

	Royalty volumes (10^6 bbl)	Cost at \$0.07/bbl (10^6\$)	Cost at \$0.15/bbl (10^6\$)
Onshore oil	15.2	1.1	2.3
Offshore oil	73.0	5.1	11.0

Projected reduced royalties owing to marketing costs are \$17.0 million to \$45.5 million per year.

References

U.S. Department of the Interior, Minerals Management Service, 1997, Threshold analysis for FERC Order 636 rule.

e. Sec. 5(b)(3)(B)--Use of affiliated pipeline-owner's costs to determine transportation reimbursements to lessee

The proposed legislation would modify the current rules for determining actual transportation costs, for reimbursement purposes, by:

1. Using a rate of return equal to twice (2 x) Standard and Poor's industrial BBB bond rate and

2. Permitting a return on fully depreciated facilities through application of the return-on-investment method.

Each one of these modifications will cause a negative royalty impact. Impact calculations are based on transportation values for 1996 taken from MMS's data base. We assume that these modifications will effect 25 percent to 50 percent of transportation allowances. This assumption is reasonable given that 75 percent of offshore oil and gas is produced by lessees with affiliates, which the majority (2/3 of 75 percent) of the time will transport their production through affiliate-owned pipelines. On the low end of the range, 40 percent of onshore oil and gas is produced by lessees with affiliates, which the majority of the time (2/3 of 40 percent) will transport their production through affiliate-owned lines.

[2]Results of survey by the Independent Petroleum Association of America presented at the Houston public workshop on October 7-8, 1997.

1) Application of Increased ROR

The current rules specify Standard and Poor's industrial BBB bond rate for the rate of return (ROR). The rate of return is used to calculate the return on investment - one of three costs components of a transportation allowance. S&P's BBB rate currently averages about 8 percent. Under the proposed legislation, this rate would double to 16 percent. The effect of doubling the ROR on the allowance taken is that the transportation allowance will be increased by an average of 30 percent. This increase is based on an analysis of typical allowance calculations using an 8 percent ROR compared to a 16 percent ROR. The projected negative royalty impact is:

Gas

	Transportation allowance taken (10^6 \$)	Increased cost effecting 25 percent of allowances (10^6\$)	Increased cost effecting 50 percent of allowances (10^6\$)
Onshore gas	29.8	2.2	4.5
Offshore gas	47.0	3.5	7.0

Oil

	Transportation allowance taken (10^6 \$)	Increased cost effecting 25 percent of allowances (10^6\$)	Increased cost effecting 50 percent of allowances (10^6\$)
Onshore oil	0.2	0.02	0.03
Offshore oil	46.7	3.5	7.0

Total projected royalty revenue loss owing to increased rate of return ranges from $9.2 million to $18.5 million.

2) Application of return-on-investment method

Under the proposed legislation, the lessee will have the option of determining transportation costs by the return-on-investment method. Under current rules, this method is applicable only to transportation facilities placed into service on or after March 1, 1988. Because the method does not terminate at the end of a facility's depreciable life, it is reasonable to assume that most lessees will choose this option to take advantage of claiming an extended return on investment and increasing their transportation costs/reimbursements to the Government. In fact, it can be reasonably assumed that companies will exercise this option when the return-on-investment method yields a greater amount than the depreciation method. This usually occurs sometime during the first half of the normal depreciation period. Under current rules, the lessee cannot switch from one method to the other once he has made an initial choice.

An unknown number of pipelines have already been fully depreciated, so they are no longer eligible for a return on investment under the current rules. For those pipelines, it is safe to assume that virtually all lessees that would choose the return-on-investment method. The effect of changing calculation methods from the depreciation method to the return on initial capital investment is that the transportation allowance will be increased by an average of 20 percent. Again assuming that 25 percent to 50 percent of current transportation allowances would be effected by this option, the projected annual negative royalty of the return-on-investment option is:

Gas

	Transportation allowance taken (10^6 $)	Increased cost effecting 25 percent of allowances ($10^6$$)	Increased cost effecting 50 percent of allowances ($10^6$$)
Onshore gas	29.8	1.5	3.0
Offshore gas	47.0	2.4	4.7

Oil

	Transportation allowance taken (10^6 $)	Increased cost effecting 25 percent of allowances ($10^6$$)	Increased cost effecting 50 percent of allowances ($10^6$$)
Onshore oil	0.2	0.01	0.02
Offshore oil	46.7	2.3	4.7

Total projected royalty revenue loss owing to the return-on-investment method ranges from $6.2 million to $12.4 million.

f. Sec. 5(c)--Charges for transportation costs beyond the delivery point

The proposed legislation would have the Government reimburse the lessee for its or its affiliate's costs of transporting RIK production through an unregulated pipeline beyond the delivery point. The cost would be either the highest rate charged for transportation provided to a third party or the fair commercial value of the transportation services.

In most cases we believe the charges will be based on tariff rates. MMS currently recognizes only **approved** tariff rates for transportation allowances, and only for **arm's-length** arrangements. For non-arm's-length (affiliated) transportation, the lessee must use actual costs. We believe the proposed legislation would require use of tariffs at face value, without the ability to look behind the rate structure.

The issue of using tariffs at face value is particularly acute for offshore oil pipelines, where FERC has renounced jurisdiction. (This issue is currently under dispute.) However, many pipelines maintain tariffs originally filed with, but not approved by FERC. **Based on actual data (the annual difference between actual costs and FERC tariffs), the negative royalty impact of permitting the use of tariffs in non-arm's-length transportation is approximately $12 million annually.**

The proposed legislation would also have the Government pay for transportation on leases issued under Section 6 of the OCSLA to the extent these lessees choose to pay royalties in kind. Transportation allowances are not now authorized for OCS Section 6 leases issued by the State of Louisiana in 1942 and 1948. **Based on prior studies, allowing transportation costs on these OCS Section 6 leases would reduce royalties by $5.3 million per year as follows:**

	Transported volumes ($x\ 10^6$)	Transportation cost rate	Transportation cost (10^6\$)
Section 6 oil	3.5	$1.2064/bbl	4.2
Section 6 gas	21.0	$0.05229/Mcf	1.1

Under current regulations, lessees shipping production on affiliate-owned pipelines must use the affiliate's actual costs to determine a transportation allowance. To use third party charges to determine a transportation reimbursement would overstate the actual shipping costs owing to inclusion of profit margins and other costs not now permitted by MMS.

According to MMS's gas RIK pilot report, MMS lost $0.0974/MMBtu in royalties by taking gas in kind from the Gulf of Mexico. Part of this loss was due to increased transportation charges through producer-owned pipelines. Indications are that the rates negotiated and paid by MMS marketers were considerably higher than the actual costs basis allowed under the current regulation. The gas RIK pilot report attributed the loss to four factors: marketing fees, increased transportation costs in producer-owned pipelines, size of bid packages, and lack of warranty volume. The report found that the marketing cost component of this loss is as much as $0.03/MMBtu. Dividing the remaining $0.0674/MMBtu equally among the other three factors, we assume a minimum increased cost attributable to transportation of $0.02/Mcf. Using the standard Btu equivalent for a barrel of oil (5.8 MMBtu/bbl), this cost will equate to $0.10/bbl. For revenue impact purposes, we assume the increased transportation cost for gas ranges from $0.02/Mcf to $0.03/Mcf, and for oil $0.10/bbl to $0.15/bbl:

Gas

	Royalty volumes (10^6 Mcf)	Increased cost at $0.02/Mcf ($10^6$\$)	Increased cost at $0.03/Mcf ($10^6$\$)
Onshore gas	237.5	4.8	7.1
Offshore gas	837.4	16.7	25.1

Oil

	Royalty volumes (10^6 bbl)	Increased cost at $0.10/bbl ($10^6$$)	Increased cost at $0.15/bbl ($10^6$$)
Onshore oil	15.2	1.5	2.3
Offshore oil	73.0	7.3	11.0

Total projected royalty revenue loss attributable to transportation on nonaffiliated pipelines is $30.3 million to $45.5 million.

References

Minerals Management Service, 1996, Royalty gas marketing pilot.

Summary of Additional Annual Royalty Costs

	Projected Onshore Revenue Impact Million $	Projected Offshore Revenue Impact Million $	Total Projected Revenue Impact Million $
a. Treating Costs - Sections 2 (18) and 2 (25)	18.9 - 37.9	66.3 - 140.0	85.2 - 177.9
b. Processing Costs - Section 3(a)(5)	1.0 - 2.0	3.0 - 6.0	4.0 - 8.0
c. Gathering Costs - Section 4(b)	3.4 - 12.4	9.8 - 29.1	13.2 - 41.5
d. Marketing Costs - Section 4(c)	3.5 - 9.4	13.5 - 36.1	17.0 - 45.5
e. Transportation costs prior to the delivery point - Section 5(b)(3)(B)			
Increased ROR (2xBBB)	2.2 - 4.5	7.0 - 14.0	9.2 - 18.5
Change to Return on Initial Capital Investment	1.5 - 3.0	4.7 - 9.4	6.2 - 12.4
f. Transportation costs beyond the delivery point - Section 5 (c)			
FERC Tariffs	0.0	12.0	12.0
Section 6 Leases	0.0	5.3	5.3
Nonaffiliated Pipeline Rates	6.3 - 9.4	24.0 - 36.0	30.3 - 45.5
TOTAL INCREASED COSTS	**36.8 - 78.6**	**145.6 - 288.0**	**182.4 - 366.6**

2. Potential Revenue Uplift

MMS estimates the potential revenue uplift from across the board RIK implementation to range from an annual loss to a maximum uplift of $35.2 million/year.

However, given the inherent risks associated with marketing oil and gas and the many provisions of H.R. 3334 that prohibit the Government from marketing its production to maximize value, the greatest potential is for no revenue gain or a revenue loss compared to the manner in which royalties are currently collected. Any potential revenue gain is currently feasible under existing law and is more likely to result from our more deliberate approach using RIK pilots.

The following preliminary analysis addresses the potential for revenue gains from implementing RIK. It is important to note that any assessment of the revenue effects of the RIK Bill is problematic due to a variety of factors, including 1) the ambiguity of the Bill; 2) the unknown contractual details of the MMS/marketing agent contracts; and 3) the dynamic interrelationships between markets, current rules, and marketing agent proceeds.

Overall Potential for Revenue Uplift. MMS believes that there is some potential for revenue gain from implementing RIK programs. Specifically, our 1997 RIK Feasibility Study concluded that the potential for enhanced revenues exists for offshore natural gas, and is possible for onshore natural gas in productive basins if certain treatment and transportation problems can be overcome. Our Feasibility Study further concluded that there is little evidence available indicating that crude oil RIK can increase royalty revenues.

Overall, revenue gain from RIK is feasible to the extent that aggregation and downstream marketing activities result in price increases that offset MMS' newly-acquired costs to market, field process, and transport production. As a general rule, the value-added effects of aggregation and downstream marketing are dramatically higher for natural gas than for crude oil, because:

- Refiners are generally not looking for large batches of crude, but are looking to purchase incremental volumes to fill refinery capacities. Thus, aggregation does not significantly increase prices.

Aggregation May Not Increase the Value of Crude Oil.

Royalty information on crude oil sales from every region of the country shows absolutely no correlation between sales prices and production volumes - the largest volume producers are not receiving the highest prices as one would expect if aggregation raises unit prices.

- There is simply not a diverse set of downstream customers for crude oil - markets are a limited number of refineries, often in the producing region. Thus, potential for downstream enhancement is limited.

  > Under crude oil RIK programs, MMS could participate in only a subset of the thin margins gained by midstream companies marketing in limited downstream markets.

  The existence of marketing companies indicates that there are profits to be made in the midstream marketing of crude oil (although it should be noted that the one marketer who testified on this issue reported a revenue loss for the last year). These companies own pipelines, trucking companies, and processing facilities. Their profits accrue on very thin margins developed partly from knowledge of and trading in crude oil market, but also from risk management activities and utilization of their own transportation and processing infrastructures. These are proceeds that the U.S. would not share under RIK scenarios.

- For the Rocky Mountain states, the potential for downstream gain is even more limited because very little production leaves the region.

  > Wyoming provides a very instructive current example of **limited downstream markets in certain regions.** The current primary market for Wyoming General Sour crude oil, about 40% of Powder River Basin crude oil, consists of a single Wyoming refinery!

MMS will be implementing its RIK pilot programs precisely to identify the revenue effects from RIK programs. Without actual tests, these revenue impacts are simply too uncertain to risk public assets. The following describes in more detail our analysis of potential revenue uplift by product.

Potential Revenue Uplift: Crude Oil. The only data that MMS has obtained concerning revenue uplift from taking crude oil to downstream markets is from the in kind programs of the Texas General Land Office (GLO) and the Province of Alberta.

1. The Alberta program has enjoyed revenue gains compared to producing region posted prices. In this program, large quantities of crude oil (165,000 barrels/day) are taken in kind by marketing agents at pipeline interconnects, and transported to refineries in midwestern markets. Results indicate a gross enhancement of 12 cents (Canadian), or approximately 8.3 cents (U.S.), over posted prices, with a net uplift of 7 cents (Canadian), or 4.9 cents (U.S.), after the marketers' fees are deducted.
   In effect, the Alberta program results in negligible increments, thus essentially duplicating posted prices, which we have found not to reflect fair market value in

the U.S. Further, such unremarkable revenue effects result under a system in which producers are required to aggregate and transport production to pipeline interconnects at non-discriminatory rates, thus greatly reducing the Province's administrative costs.

2. The Texas GLO RIK program is not mandatory and only takes about one-half of its crude oil royalty volume in kind from highly producing fields and markets using internal staff. In fiscal year 1996, the Texas GLO took almost 900,000 barrels of crude oil in kind. This program is characterized by GLO as essentially revenue neutral. We should point out that when any gain occurs (in some instances a gain of 18 cents was realized), it is because Texas operates under more favorable conditions than H.R. 3334 allows -- the program is not mandatory and they choose not to take production from small volume leases less than 10 barrels per day; they don't pay transportation to the pipeline interconnect; and they enjoy preferential status on pipelines in the State.

The Alberta and Texas experiences indicate that crude oil RIK can result in values essentially equivalent to postings, if implemented at the option of the Province/State, under the favorable transportation conditions and favorable lease terms and regulations as described above. Without these conditions, it is unlikely that any revenue increases can be realized. These conditions required for a successful RIK program are not included in H.R. 3334.

The ability to secure revenue gains also depends on regional market characteristics, specifically the ability to move production away from areas of long supply to those with shorter supply and/or higher demand. With this in mind, it is instructive to look at the largest concentrations of U.S. oil production - Wyoming, southeastern New Mexico, and offshore Gulf of Mexico production.

Wyoming is a crude oil producing area that is very long on production, and does not enjoy good access to markets other than local ones. It is unlikely that access will improve. Thus, it is difficult to imagine the creation of new, higher demand markets for Wyoming crude. Although we will test the revenue impacts in our pilots, at this point we can not estimate any gain from downstream marketing under an RIK program.

For southeast New Mexico and offshore Gulf of Mexico production, access to better markets than local ones is possible, considering the well-established physical and trading connections to the large Midland, TX and Cushing, OK markets. Thus, it is theoretically possible that some revenue gains can be secured relative to lease sales by engaging in downstream marketing through RIK implementation.

To estimate a maximum amount for this gain, we use Alberta and the GLO results described above; that is, a maximum revenue gain of between 5 and 18 cents per barrel is possible for southeast New Mexico and Gulf of Mexico Federal production accruing from movement to broader markets. Using the 11.5 cents per barrel midpoint, this translates to a potential gain of some $7.4 million annually for this production. However, given that 40 percent of royalty oil must be provided to eligible small refiners based on the lowest prices received, this revenue gain could only be realized on 60 percent of the oil, for a maximum gross revenue gain of $4.4 million annually. We believe that this is a maximum value because:

1. Both the Alberta and Texas gains were calculated in comparison with posted prices, and MMS current revenues are, on average, higher than postings.

2. The estimate assumes ideal conditions for RIK that are found under the Alberta and Texas GLO systems but not under H.R. 3334 (e.g., non-mandatory RIK, favorable transportation, delivery by the lessee to pipeline interconnects).

Revenue uplift from taking crude oil in kind from producing regions other than those assessed above are not expected to result in increases in revenues, and would result in an unquantified revenue decrease due to marginal properties involved. Thus, the estimate for revenue uplift from crude oil RIK ranges from less than zero to a maximum of $4.4 million.

> Based on its 1995 gas marketing pilot, MMS estimates it would have lost over $100 million annually if all Federal gas were taken in kind.

Potential Revenue Uplift: Natural Gas. During the market survey phase of MMS' Feasibility Study, we discussed potential revenue enhancements with several gas marketers. A detailed study of potential revenue impacts has not been performed to date. While actual revenue enhancements would depend on what marketers would be willing to bid for Federal gas, the marketers stated that MMS possessed ample volume in the Gulf of Mexico (about 2.3 Bcf/day) to provide incentive to marketers to bid for Federal volumes.

Marketers stated they could increase value to the Federal gas via aggregation of volumes and performing downstream services which generally enhance the value of the gas. Marketers stated they would be willing to share the enhancements with the Federal lessor, in return for the large volumes. It was access to these downstream markets and the potential sharing of downstream revenues which led to the Feasibility Study conclusion that there was potential for revenue enhancements and that MMS should look in further detail at the potential for capturing this revenue.

<u>OCS Gulf of Mexico Gas.</u> The following are the potential revenue enhancements that may be captured based upon discussions with gas marketers. The proposed RIK legislation mandates many requirements that would dampen the ability to achieve these enhancements.

A review of royalty payments made for the proposed gas valuation regulations showed that MMS essentially receives index prices less transportation. Under RIK, gas marketers stated that MMS would also receive index prices as a base price for its gas. Thus, the gas portion is essentially a wash.

In 1997, marketers stated that there was about a 4 cent gross uplift that they make on natural gas. To achieve this gross uplift, they incur costs to aggregate, trade, and perform risk management activities, such as hedging. A net margin of 1 to 2 cents may exist. The best MMS could expect would be to share in this 1-2 cents. A 1 cent per MMBtu uplift applied to the 2.3 Bcf/day of royalty volume produced from the Gulf of Mexico equals a maximum uplift of $8.4 million/year for the gas (non-liquid) portion.

With respect to natural gas liquids, previous reviews by MMS indicated that lessees who report processed gas and liquids pay about 2.3% or 4 cents per MMBtu more in royalties than those who report unprocessed gas. This level of uplift is possible for the two-thirds of OCS royalty gas in the Gulf of Mexico that are currently paid as unprocessed gas, a volume equalling 1.5 Bcf/day. A maximum revenue gain of this amount translates to approximately $22.4 million/year for the liquids portion of the natural gas stream.

We conclude that the maximum potential revenue gain for offshore natural gas in the Gulf of Mexico equals about $30.8 million/year, an increase that can be secured without this legislation. Moreover, it is also possible that the following provisions of H.R. 3334 would actually result in revenue decreases: 1) QMAs selling to affiliates at less than market values; 2) individual QMAs for each lease; and 3) QMAs marketing less successfully than producers and their affiliated marketers. Thus, the estimate for revenue uplift from offshore natural gas RIK ranges from less than zero to a maximum of $30.8 million/year.

<u>Onshore Natural Gas.</u> It is possible that taking natural gas in kind from Federal leases in a highly prolific basin would result in revenue gains through the same dynamic as described above for Gulf of Mexico gas. Some have suggested that taking in-kind gas from New Mexico's San Juan Basin (onshore's most prolific area) may increase value from aggregation and trading on basis differentials between California and west Texas markets. However, MMS has not been provided any specific information indicating that this is true. In fact, the San Juan Basin is beset with significant capacity constraint problems in gathering systems and high processing costs that may hinder in kind operation. We conclude that there is insufficient data to provide an estimate of direct revenue impacts from onshore gas.

Total Potential Direct Revenue Effects. Subject to the assumptions and caveats mentioned above, we estimate **a total potential revenue uplift of between less than zero to $35.2 million annually from across the board RIK implementation.**